valve section classified as an SCC Susceptible Site does not result in a failure attributed to SCC, the retesting interval is extended one year. Consequently, the re-testing intervals could increase from 3 years to 4, 5, etc. years as long as no other failures were attributed to SCC. The hydrostatic retest criteria have been effective, but will require some changes to accommodate the next integrity assessment criteria of the IMP regulations.

All SCC that Operator D has observed has been confined to approximately 6 valve sections and classified as classic or high-pH SCC. All observed SCC has been oriented longitudinally, or no circumferential SCC has been observed. Observed SCC has generally been on the lower portion of NPS 26 and 30 pipes, and associated with disbonded coal tar enamel (80 percent of incidents) or asphalt coating (20 percent).

Operator D has attempted ILI for SCC using both the elastic wave and EMAT tools, but the experience was unsatisfactory. Operator D's experience with both types of ILI tools was that the tool provided false-positive indications of SCC that were not SCC, and SCC was not identified in some cases where colonies were known to exist. Consequently, Operator D will continue to rely upon hydrostatic testing for the near future as the most reliable method for determining if a valve section has suffered SCC that is a threat to pipeline integrity.

Operator D is currently revising their SCC management program for compliance with the gas integrity rule and considers the following five factors as the most significant for assessing the SCC threat on a pipeline segment:

1. High operating temperature.
2. High operating pressure.
3. Coating condition.
4. Location (i.e., downstream from compressor station as well as geographic location).
5. Cathodic protection effectiveness.

While other factors may be useful for threat assessment, Operator D considers them secondary to these five factors.

A corrosion technician is typically present at an excavation for visual examination of pipeline condition. Operator D has employed magnetic particle testing (MT) of exposed pipe surfaces in the past, but not as a routine practice for all exposed with disbonded coating. The revised SCC management program will include use of wet, black MT on white contrast for examination of pipe under disbonded coating. Contract inspectors will perform the MT in the near term, but Operator D anticipates training and equipping in-house employees, such as the corrosion technicians, for MT.

When SCC has been discovered, Operator D has employed grinding to remove the cracking and determine depth. Operator D has not found manual UT useful for determining depth of SCC colonies.

Operator D is an active member of PRCI. Operator D has investigated soils and site characterization for prediction of the location of classic or high-pH SCC, but has not found either useful.

New construction and replacements are installed with line pipe that is externally coated with FBE.

Multiple possibilities for industry initiatives were discussed:

- Improved ILI of Gas Transmission Pipelines for SCC

  Resources should be committed to development of reliable ILI for detection of SCC in gas pipelines (without use of liquid slug trains to facilitate use of UT pigs).

- Database of SSC-related Information

  The potential for developing an industry-wide database of information related to the SCC threat in gas pipelines was discussed in some detail. Challenges to development of such a database include development of an industry standard for collection of data associated with (1) in-service and hydrostatic testing SCC failures, and (2) excavations for direct examination. An industry standard for data collection would need to be developed under the direction of an industry group (INGA, PRCI, etc.) with funding.

  The perceived benefit of an industry-wide database could be more cost-effective assessment of the SCC threat of each pipeline system where trends from the database were applied. Given the cost of hydrostatic testing and excavation for direct examination, more cost-effective assessment of the SCC threat could conserve significant resources for addressing other threats that are more significant to public safety.

- Post-Failure Response

  An industry standard for Incident Response and Return-to-Service after an in-service failure attributed to SCC is desirable.

10.4.5 Operator E

Operator E operates thousands of miles of natural gas pipelines in Canada and the US. The coating systems on their pipelines, which vary widely in diameter, are approximately equally divided between tape, asphalt, FBE, and yellow jacket.

Operator E has been very involved in all issues relating to SCC, especially near neutral-pH SCC. They noted that they view SCC as a series of factors; i.e. as a continuum of events, rather than a single isolated event. The series includes:

- Incubation
- Disbondment
- Initiation
- Growth
- Coalescence
- Mechanical drivers, possibly including fatigue

They initially used soils models to provide estimates of SCC possible locations. They now view such models as a tool to correlate with potential coating disbondment segments. Drainage, local topography, soil disposition and similar aspects of soil models, tied with time in service, are seen as predictors of potential coating failures, though not necessarily SCC areas. Further pipeline operating information such as temperature and/or pressure information are used to aid the assessment.

They have performed thousands of digs since 1986. All excavations are checked for the existence of SCC. Contractors trained in SCC assessment and associated data gathering perform these digs. Operator E has never seen SCC under FBE disbondment and note that FBE does not shield CP. They have not seen any cracking at the girth welds for FBE coated pipe, where shrink sleeves are employed.

While Operator E cooperates with and supports organizations such as PRCI in basic research, they also perform additional in-house research relating to operational issues.

They extensively use risk-based models, with calibration against field data. With its extensive system of pipelines, they are able to develop and maintain reliable in-house statistics for these models. The calibration with actual field experience was underlined as a requirement for meaningful model development and predictions. The models include not only a stochastic estimate of failure, but also of potential consequences such as injury, societal risk, financial cost, and regulatory/perception impact. Digs are prioritized based on this model. Locations are often re-inspected to determine growth rates, if any.

Especially for gas lines, Operator E does not view any ILI tool as effective for SCC detection. Hydrostatic testing is their tool of choice, although they see promise in emerging ILI technology. They have used a UT tool in a liquid slug, but note the laborious process and costs as well as difficulty in speed control. Initial hydrostatic testing is a 1-hour strength test at 100-110 percent SMYS, followed by a 2-hour leak test of 90 to 100 percent SMYS. They noted that they are concerned with crack growth during a long duration spike test, so any spike test is limited to a 5-minute hold. They use their risk management procedures to establish retest intervals. The distribution of crack sizes and rates are developed stochastically (i.e. in distributions rather than single deterministic estimates). The risk decision is based on the outcome of this model. They have found that the use of a Paris crack-growth model under-predicts the amount of damage.

They have correlated near neutral-pH SCC with distance from the stations with most instances occurring in the first third, very few in the middle third, and maybe one in the last third.

Operator E performs wet fluorescent MPI whenever there is evidence of a disbonded coating. They will blunt the cracks if required and practicable, and assess the remaining strength using standard procedures (e.g. RSTRENG or similar). As required, they may employ a pressure containment sleeve with no standoff. They do not employ composite wraps, noting that it is not cost effective in their experience.

If an incident occurs, they will evaluate the situation to employ the correct pressure reduction before final implementation of their return-to-service plan. A rule-of-thumb is to examine the operating records and reduce to 90 percent of the 60-day high pressure or 80 percent of the failure pressure. Additional information, such as the presence of swamp weights, may cause further reductions. This reduction will be re-evaluated if the interval to return of service is prolonged. They work closely with regulatory groups in that time. They also noted that they meet twice a year with interested regulatory groups in any case to discuss upcoming plans.

Operator E cautioned that a central database may not produce much benefit and instead stressed that regular communication between interested groups is of greater value. They support and sometimes participate in the development of ILI tools but recognize this is a lengthy process.

10.4.6 Operator F

Operator F is a part of a larger pipeline group. The interview was limited to the still extensive gas transmission pipeline experience, encompassing most of the common pipe sizes that transport gas from the Gulf Coast to the Northeast U.S. and points in between.

Operator F has experienced in-service and hydrostatic testing failures attributed to classic or high-pH SCC oriented in the longitudinal direction. Longitudinal near neutral-pH SCC has not been observed in the Operator F system. The classic SCC has been associated with disbonded coal tar enamel coating. Operator F was an early adopter of fusion-bonded epoxy (FBE) coating and has over 30 years of experience with FBE, and has observed no SCC of pipe coated with FBE.

SCC has been observed in line pipe of multiple diameters, wall thicknesses and grades, supplied by multiple manufacturers and installed in multiple years with multiple maximum allowable operating pressures (MAOPs). Operator F has observed SCC in multiple states and in multiple types of soils and moisture conditions.

Operator F relies upon hydrostatic pressure testing and magnetic particle testing (MT) for detection of SCC. Operator F has concluded that current ILI technology for detection of SCC in gas pipelines is not reliable and that use of liquid slugs to permit UT inspection is not cost effective.

Operator F uses spike hydrostatic testing in which the aim stress is 105 percent of SMYS, the minimum stress at the high point of a segment is 100 percent SMYS and the maximum stress at the low point is no more than 110 percent SMYS. The initial test period is 1 hour followed by 7 hours at a stress of 90 percent of SMYS or greater. Operator F may follow hydrostatic testing with a flame-ionization leak survey on a case-by-case basis. For example, detection of a leak during a spike hydrostatic test could be cause to follow up with a flame-ionization leak survey.

Operator F employs MT of all bare pipe surfaces exposed for direct examination. Operator F uses MT with multiple types of magnetic particles (dry, wet visible, wet fluorescent, black on white, etc.), but concludes that MT with dry powder is sufficient to detect SCC on dry pipe surfaces when operators are properly trained. Wet visible magnetic particles are the preferred method for wet pipe surfaces. Application of dry powder to the bottom of the pipe is recognized to require more training and skill than the top of the pipe or other types of magnetic particles, but has proven satisfactory.

Operator F developed and presents weeklong workshops that address all types of direct examination of exposed pipeline segments as a part of the operator qualification program. Typical topics include assessment of external and internal corrosion, mechanical damage, SCC, etc. The weeklong workshops include both lecture and hands-on sessions focused upon detection of SCC as well as distinguishing SCC from other types of surface anomalies. The workshops include repair methods, including hands-on training for the grinding of pipe imperfections.

Operator F is an active member of PRCI. Operator F does not consider soils characterization models applicable to assessing the likelihood of classic SCC.

Operator F observes that visual appearance of SCC colonies is generally related to depth of penetration. For example, a colony of relatively short, unlinked cracks is likely to be relatively shallow. On the other hand, a colony that contains linked cracks with significant linear extent is likely to penetrate a significant portion of the pipe wall. Advanced NDE techniques such as focused UT, eddy current, etc. have been employed to estimate maximum depth of SCC, but have proven unreliable, apparently due to interference of nearby cracks. Consequently, Operator F considers grinding as the most reliable method to estimate depth of SCC.

If grinding is sufficient to remove shallow SCC detected by MPI, Operator F re-coats the exposed pipe and returns to service. If SCC is too deep to repair by grinding, Operator F either installs a Type B (pressure containing) sleeve or replaces the section containing the SCC.

If a pipeline segment experiences an in-service leak or rupture attributed to SCC, adjacent pipe joints are subjected to MT until pipe joints free of SCC are located on either side of the failure. All observed SCC is repaired and the segment returned to service. A risk assessment is performed and an Integrity Assurance Plan is developed to remediate the possibility of SCC in the area. Operator F applies the criteria in ASME B31.8S Appendix A3 for assessing the threat of SCC.

Operator F is in the process of developing a procedure for direct assessment of pipelines for SCC based on the existing draft version of the NACE SCCDA recommended practice.

Operator F would not be inclined to contribute to, or draw from an industry-wide SCC database. Beyond the difficulty of implementing an industry-wide database, Operator F has a significant internal database that is directly related to their system. An industry-wide database would likely have more potential value for an operator with less experience in dealing with SCC.

10.4.7 Operator G

Operator G operates approximately 7,700 miles of pipeline in 360 testable segments to transport a variety of products. The product mix is approximately one-third crude oil, one-third refined products and one-third highly volatile liquids and chemicals. Pipe sizes ranges from NPS 2 through 40.

Operator G has observed SCC in two testable pipe sections located in southern Louisiana. One of the pipe sections is NPS 8 and the other is NPS 16, both were installed in 1954 and coated with coal tar.

The first observed SCC was a hydrostatic test rupture in the NPS 8 section in 1985. No further SCC has been observed in the NPS 8 segment. The NPS 16 section suffered an in-service failure in 1993 and six hydrostatic testing failures attributed to SCC in 1994. Another hydrostatic testing failure occurred during a retest in 1999, potentially indicating that SCC remained active at least a portion of the time between the 1994 and 1999 tests.

All these SCC incidents were attributed to high-pH or classical SCC. These SCC incidents were generally associated with disbondment of the coal tar coating possibly attributed to soil stresses or possibly due to the quality of coating installation during initial construction. The operating temperature of these pipeline segments rarely, if ever, exceeds 100°F, which leads Operator G to believe that disbondment is not attributed to elevated temperature of transported fluids. No records have been located relating to soil and water samples collected at the time of the SCC failures for detailed characterization of the soil associated with the SCC.

The procedure for returning a pipeline to service after an in-service failure is determined on a case-by-case basis, depending upon the cause of the failure. If the cause of a failure were not apparent i.e. associated with mechanical damage, external corrosion, etc., the pipe would be sent to a laboratory for analysis in an attempt to determine the cause of the failure.

Should SCC be detected by magnetic particle examination, a typical repair plan would involve lowering the operating pressure to 80 percent of the highest operating pressure experienced during a 4-hour period in the two months prior to the time of discovery of the SCC per DOT guidance. If the SCC can be removed by grinding without reducing the pressure carrying capacity of the segment, the location would be recoated and returned to service following grinding. If the SCC can be removed by grinding, but the depth of grinding reduces the pressure carrying capacity of the pipe, a composite sleeve, a steel welded sleeve, or a fabricated mechanical device may be applied to restore the desired pressure rating. If the SCC depth is such the SCC cannot be removed by grinding, a temporary repair will be installed until the line can be taken out of service for a permanent pipe replacement. (Operator G's repair criterion does not currently allow permanent repair of a longitudinally oriented crack defect except with replacement pipe.)

Operator G has employed several ILI tools, including caliper for deformation conditions, UT and MFL for wall loss and TFI for seam imperfections, but has not used the UT tools designed to detect SCC yet. Application of special UT crack detection tools (or hydrostatic pressure testing) in pipeline segments susceptible to SCC is planned.

Operator G has screened approximately 360 testable pipeline segments for potential susceptibility to high-pH or classical SCC using the five SCC screening criteria in ASME B31.8S Appendix A3.3 with minor modification to adapt the criteria from gas to liquid pipelines, specifically converting distance downstream from compressor station to distance from pump station.

Operator G also has access to the draft version of the NACE SCCDA recommended practice, which recommends that screening for potential susceptibility to near neutral-pH SCC not consider operating temperatures above 100°F as a criterion. Therefore, Operator G has screened for potential high-pH SCC using the five SCC screening criteria identified in ASME B31.8S, but has also screened for potential near neutral-pH SCC using four of the five criteria identified in ASME B31.8S (without the 100°F temperature criterion). The screening process identified 24 segments at this time as potentially having susceptibility to near neutral-pH SCC, including the two segments that had suffered high-pH SCC. Segments where either high or near neutral-pH SCC has been detected will be assessed using specialized ILI technology or hydrotesting. Segments that are identified as potentially susceptible to either type of SCC will be subjected to additional NDT including Magnetic Particle Inspection during routine maintenance or integrity management activities where pipe coating is being removed in an attempt to locate any other SCC occurring on these pipeline segments.

Operator G has identified a need for and is planning for additional training of company personnel in SCC awareness and magnetic particle inspection for detection of SCC.

Operator G is also considering the application of External Corrosion Direct Assessment to approximately 28 pipeline segments (not the 24 segments identified as potentially susceptible to SCC) that are not amenable to either hydrostatic testing or ILI. They are employing a consultant to perform black on white magnetic particle examination for cracks when a pipeline segment is excavated for direct examination. Although the magnetic particle examination is not employed solely to detect SCC, any SCC present in the locations examined directly should be revealed. If SCC is detected in any of these ECDA segments, they will be moved into the "susceptible to SCC" category and will be assessed by either hydrotesting or ILI. Operator G is considering the application of SCCDA in the future, but is currently awaiting completion of the NACE SCCDA document.

New construction and replacements are installed with line pipe that is externally coated with FBE at a coating plant and FBE joint systems are applied to girth joints during construction. Operator G also has specifications in place for pipe procurement, hot bends manufactured from line pipe, pipeline construction, CP design and operation, as well as the FBE coating specifications mentioned to also help eliminate the cause of the SCC phenomena in new pipeline construction.

Operator G is an active member of PRCI and reviews the results of research into pipeline integrity management for possible inclusion in its IMP. Operator G also has representatives on multiple API committees and NACE International committees developing other integrity-related technology.

The potential value of an industry database for collection of SCC related information was discussed. Operator G observed that the API Pipeline Performance Tracking System (PPTS) sponsored by the API Operators Technical Committee already contains integrity-related information that is useful to operators of hazardous liquid pipelines. The data fields collected in PPTS track accidents on hazardous liquid, carbon dioxide, and anhydrous ammonia pipelines attributed to approximately 40 possible pipe failure causes, including SCC.

Operator G supports the API initiative requesting a revision of § 195.452 to align the repair criteria and other issues for hazardous liquid pipelines with those applicable to gas transmission pipelines. Operator G also supports a possible revision of API Standard 1160: *Managing System Integrity for Hazardous Liquid Pipelines* to incorporate revisions to the IMP Regulations and possible inclusion of the concepts in ASME B31.8S.

Operator G also encourages pipeline regulators to consider a more performance-based rather than a prescriptive- and procedural-based perspective when reviewing integrity management programs. Operator G feels this approach will provide pipeline operators with greater flexibility to produce more efficient and effective integrity management programs and demonstrate that the performance of the programs meets the desired objectives.

Operator G desires from this SCC research project

1. Confirmation that ASME B31.8S and NACE SCCDA are accurate for SCC screening applicability (or development of better tools if they are not accurate).

2. Identification of better ILI technology for more accurate SCC sizing and locating.

3. Knowledge of accurate mathematical models with easy to use analysis to determine fitness for purpose of pipe with SCC.

10.5 References

Internally developed material and operator interview responses.

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11 SCC in Integrity Management

11.1 Scope Statement

"Develop a practicable procedure regarding how to assess SCC in operating pipelines within the context of integrity management."

This work item is addressed first in Chapter 10 and concluded in this Chapter.

11.2 Assessment of SCC Risk Factor in Integrity Management Plans

The OPS Integrity Management Plan protocols establish the general procedure for regulatory oversight of an operator's Integrity Management Plan.

11.2.1 Natural Gas Pipelines – Protocol Review

There are four draft OPS Gas Integrity Management inspection protocols that specifically mention SCC. The first of these is Protocol C.1, Threat Identification. Item a. states:

"…verify that at least the following nine categories of threats have been evaluated:

i. Time-dependent threats: (1) external corrosion, (2) internal corrosion, and (3) stress corrosion cracking;…"

The next two are Protocol D.12, SCCDA Data Gathering & Evaluation, and Protocol D.13 SCCDA, Assessment, Examination, & Threat Remediation. Protocol D.12 states:

"Verify that the operator's SCCDA evaluation process complies with ASME/ANSI B31.8S, Appendix A3 in order to identify whether conditions for SCC of gas line pipe are present and to prioritize the covered segments for assessment.

a. Verify that the operator has a process to gather, integrate, and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment.

   i. Verify that the operator gathers and evaluates data related to SCC at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC.

   ii. Verify that the data includes, as a minimum, the data specified in ASME/ANSI B31.8S, Appendix A3.

   iii. Verify that the operator addresses missing data by either using conservative assumptions or assigning a higher priority to the segments affected by the missing data, as required by ASME/ANSI B31.8S, Appendix A3.2."

While Protocol D.13 states:

"Verify that covered segments (for which conditions for SCC are identified) are assessed, examined, and the threat remediated.

a. Verify that, if conditions for SCC are present, that the operator conducts an assessment using one of the methods specified in ASME/ANSI B31.8S, Appendix A3.

b. Verify that the operator's plan specifies an acceptable inspection, examination, and evaluation plan using either the Bell Hole Examination and Evaluation Method (that complies with all requirements of ASME B31.8S Appendix A3.4 (a)) or Hydrostatic Testing (that complies with all requirements of A3.4 (b)).

   i. Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with ASME/ANSI B31.8S, Appendix A3.4 (b)) within 12 months of the failure, using a documented hydrostatic retest program developed specifically for the affected segment(s), as required by ASME/ANSI B31.8S, Appendix A3.4.

c. Verify that assessment results are used to determine reassessment intervals in accordance with §192.939(a)(3); (see Protocol F)."

And the last inspection protocol that references SCC is Protocol F.4, Reassessment Intervals, which states:

"Verify that the requirements for establishing the reassessment intervals are consistent with section §192.939 and ASME B31.8S…"

It goes on to state: "If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to Protocol D for evaluating the operator's interval determination."

49 CFR 192.939(a)(3) describes the required method for determining the reassessment interval if SCC direct assessment is used, but limits the maximum interval to that specified in AMSE B31.8S, Section 5, Table 3.

Other Protocols that are related in varying degrees to addressing an SCC threat include:

- Protocol B.1, Assessment Methods,
- Protocol F.1, Periodic Evaluations,
- Protocol F.2, Reassessment Methods, and
- Protocol H.6, Corrosion.

A description of SCC and the threat it poses to pipelines is presented in Section 4 of this report. Prevention, Detection and Mitigation of SCC are discussed in Sections 5, 6 and 7, respectively.

The most discussed subject related to SCC in the Protocols is SCCDA. The forthcoming NACE recommended practice on SCCDA is discussed in Section 6.3 and, to a lesser extent, Section 8.2 of this report. A part of the SCCDA process is determining appropriate reassessment intervals.

The use of ILI for detection of SCC is discussed in Section 6.2.

11.2.2 Hazardous Liquids Pipelines – Protocol Review

The current Hazardous Liquids Integrity Management Inspection Protocols specifically mention SCC in two locations. Protocol #5.01, Risk Analysis: Comprehensiveness of Approach, states:

"An effective operator program would be expected to have the following characteristics:

1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
    - external and internal corrosion
    - stress corrosion cracking
    - materials problems
    - third party damage
    - operator or procedures errors
    - equipment failures
    - natural forces damage
    - construction errors
2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
    - health and safety impact
    - environmental damage
    - property damage
3. Integration of results from the analysis of how pipeline failures could affect high-consequence areas from the segment identification process."

Protocol #6.02, Preventive & Mitigative Measures: Risk Analysis Application, states:

"Operators must conduct a risk analysis as part of the evaluation of preventive and mitigative measures, including a number of specific risk factors. In addition to the required set of factors, there are other factors that are relevant to the preventive and mitigative measures evaluation. An effective operator program would be expected to have the following characteristics:

1. Consideration of all risk factors required by §195.452(i)(2) in the risk analysis applied to the preventive and mitigative measures evaluation. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. A risk analysis process that addresses all other relevant factors that constitute a threat to pipeline integrity (e.g., external and internal corrosion, third party damage, operator or procedures error, equipment failures, natural forces damage, stress corrosion cracking, materials problems, construction errors, various operating modes).
3. A risk analysis process that addresses all other relevant important consequences of pipeline failures (e.g., population impacts, environmental damage, property damage).
4. Measures to assure that the analysis are up to date prior to use (e.g., pipeline data and configuration assumptions verified to be current prior to evaluating the relative impact of a proposed preventive or mitigative measure)."

Similar to the Natural Gas Inspection Protocols, there are several other protocols that are related in varying degrees to addressing an SCC threat:

- Protocol #2.01, *Baseline Assessment Plan: Assessment Methods*,
- Protocol #3.05, *Integrity Assessment Results Review: Identifying and Categorizing Defects*,
- Protocol #3.07, *Integrity Assessment Results Review: Hydrostatic Pressure Testing*,
- Protocol #3.08, *Integrity Assessment Results Review: Results from the Application of Other Assessment Technologies*,
- Protocol #4.01, *Remedial Action: Process*,
- Protocol #4.01, *Remedial Action: Implementation*,
- Protocol #5.02, *Risk Analysis: Integration of Risk Information*, and
- Protocol #5.03, *Risk Analysis: Input Information*.

11.3 Specific Protocol Issues to be Addressed Regarding SCC

Based on the protocols discussed above, an operator's IM plan, whether liquid or gas, should contain the following information with respect to SCC:

1. *Data collection Procedure*:

Plan Document: A written program that includes the data required to be collected to evaluate SCC susceptibility; a procedure to collect, collate and maintain such data; a procedure that determines and justifies conservative estimates made in lieu of field data; and procedures, as appropriate, to be used in the data collection methodology and/or qualification of personnel assigned to gather the data.

Comments: Data collection is essential to a robust pipeline integrity management program. For evaluation of SCC susceptibility, such data would include changes in cathodic protection requirements that may indicate degradation of the coating system. Leak history and failure evaluations can lead to trends in the performance of the pipeline. The presence of SCC as detected by ILI can indicate areas of potential problems. Pressure cycles and the magnitude of pressure cycles during normal and abnormal operation are important to crack growth prediction and remaining life estimates.

There are three general sources of data to consider in examination of SCC: 1) Historical data including leak and rupture history, ILI and hydrostatic tests, 2) Pipe data including geometrical (OD, wall), mechanical and metallurgical properties, as well as the operating characteristics and 3) On site data such as observations from examinations of digs. All three sources of data must be carefully examined to consider the available options.

2. *SCC Threat Assessment Procedure:*

Plan Document: A written procedure for collection and evaluation of information, including data from ILI, past hydrostatic tests and/or direct examination, that operators can use in conjunction with their route mapping and pipeline system operational characteristics to prioritize those segments that may be more susceptible to SCC. This procedure could form part of an operator's linewide threat assessment plan and/or External Corrosion Direct Assessment (ECDA) process as such as defined in Non-mandatory Appendix B of ASME B31.8S. An example of an assessment procedure for high pH SCC is given in the report *Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines*, by Eiber and Leis (1998). The minimum criteria for gas lines is presented in B31.8S, Appendix A3. Evidence of update procedures and the assurance of competent personnel who perform/evaluate the update should be included in the plan document.

Comment: There are a number of approaches that can be used to assess and/or prioritize pipeline susceptibility to SCC, and no single method is recommended above others. Rather, the important point is that a consistent approach is used that includes both the technical factors as well as other societal and environmental factors that contribute to the overall risk of a potential SCC incident. Also, it is important that this procedure is maintained and updated as new technical data is collected, new information regarding SCC is developed, and/or new information regarding the external consequences is received. The viewpoint must be that the procedure is really a methodology to continually refine understanding of the threat posed by SCC.

It is noted that this procedure is also used by the operator to demonstrate that his pipeline is not susceptible to SCC. The mere fact that no SCC-related incident has occurred on a pipeline segment should never be considered as evidence that the pipeline is not susceptible to SCC.

3. *Examination Procedure for SCC:*

Plan Document: A written procedure to be used during direct examination that addresses the identification and examination procedures relative to SCC. It should address factors that will trigger more detailed SCC-specific examination, such as evidence of a disbonded coating during a visual examination. The procedure should identify the data collection effort, as well as the specifics of the direct examination technique(s) applicable, e.g. surface preparation, types of magnetic particle or dye penetrant, etc. It should also address hydrostatic test procedures.

Comments: See Chapter 6 of this report for additional information.

4. ***SCC Evaluation Procedure:***

Plan Document: A written procedure should be evident that shows the steps to be followed when SCC is detected. This should include a fitness-for-service assessment of the pipe segment containing the SCC, possible mitigation and/or preventative steps, as well as a procedural outline for continued monitoring and reassessment.

Comments: Once SCC susceptibility is identified in a pipe segment, it is prudent to establish a focused program to track SCC indications, establish and monitor growth and growth rates, develop a remedial and/or preventative program, and consider investigation techniques such as high-resolution ILI crack detection tools and /or increased hydrostatic testing. Such a program must be well documented, auditable, and consistent with best industry practice.

Testing and/or inspection intervals depend on the growth rate of SCC. Ideally, the retest intervals should be set to detect cracks that will not grow to critical size before the next test. This depends on a clear understanding of the crack mechanism within the operational parameters of the system, as well as an understanding of the crack growth mechanism and its consequent growth rate. Crack growth is calculated using conservative methods so as to predict the fastest crack growth rate. The time to failure is then computed by dividing the difference between the critical defect at the operating pressure and the critical depth at the test pressure by the calculated crack growth rate. Since such a definitive understanding is not currently achievable for most operating pipelines, consideration of safety factors which account for the associated uncertainty is also recommended.

5. ***SCC Remedial Action:***

Plan Document: A written plan that details actions to be taken when the evaluation procedure finds that pipeline integrity has deteriorated to non-maintainable levels. This would include field procedures (or references to such) for the safe implementation of repair and retrofit procedures, coating replacement, and associated safety considerations. The plan should also detail procedures (or references to such) for incident response.

Comments: Repair and mitigation methods are discussed in Chapter 7. 49 CFR 190 through 199 requires each operator to prepare a response to leaks and failure incidents, including those caused by SCC. The response procedure identifies a qualified team who can recognize SCC failure and understand the information that should be recovered from the incident in order to expedite safe repair and extend the evaluation, as required, to adjacent pipe segments. If a section of pipe is removed, the pipe must be preserved for metallurgical analysis.

The following is not specifically required by the protocols but should be considered. It would be difficult to provide effective threat protection against SCC if such a program was not in place:

6. ***SCC Education/Awareness:***

   A written procedure addressing an education/awareness program, especially for field personnel discussing SCC, the threat posed, causal and incident factors, and identification during direct examination. The procedure should address operator qualification in this regard, specifically in-house trained personnel, or a key third-party contact working with the organization that can readily recognize SCC.

Items 1, 2 and 5 above should be in evidence for all IM plans. To make any assessment of the threat posed by SCC, even when there is a presumption that the conditions for SCC do not exist for a pipeline, basic data collection and an initial assessment should be concluded. As a result of this initial exercise, and in the event that an operator concludes that the conditions for SCC are not identified, local site threat assessments (i.e. extension of item #2) would be obviated. Also, in this case, items 3 and 4 would not be required.

11.4 References

Eiber, R. J., and B.N Leis. 1998. *Protocol to Prioritize Sites for High-pH Stress-Corrosion Cracking on Gas Pipelines*. PRCI. Project PR-3-9403, L51864.

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12 Response to SCC Incidents

12.1 Scope Statement

"Identify recommended actions to be taken by pipeline operators to facilitate response and assure appropriate remedial measures are implemented following an SCC-related incident.

12.2 Regulatory Oversight in Post-SCC Incident Response

There are two separate agencies involved in the oversight of a pipeline accident:

1) National Transportation Safety Board (NTSB): The NTSB is an independent Federal agency charged by Congress with investigating significant accidents in pipelines, i.e. pipeline accidents involving a fatality or substantial property damage, and issuing safety recommendations aimed at preventing future accidents. It is not part of the Department of Transportation, nor organizationally affiliated with any of DOT's modal agencies. The Safety Board has no regulatory or enforcement powers. The Board derives its authority from 49 CFR.

2) Office of Pipeline Safety (OPS) : In 1968, Congress adopted the first comprehensive federal pipeline safety statute, the Natural Gas Pipeline Safety Act (NGPSA), in response to a tremendous increase in the nation's use of natural gas, the concurrent growth in population, and several well-publicized gas pipeline accidents. Eleven years later, in 1979, Congress passed a parallel regulatory program for hazardous liquid pipelines with passage of the Hazardous Liquid Pipeline Safety Act (HLPSA). Under both statutes ('the Acts'), the U. S. Department of Transportation (DOT) was granted primary regulatory authority to establish reporting and record-keeping requirements for the industries, to set technical standards for the design, construction, testing, and maintenance of pipeline facilities, and to enforce safety standards. This authority was delegated, in turn, to the Office of Pipeline Safety (OPS) in the Research and Special Programs Administration. By 1970, OPS had adopted core requirements for the gas pipeline industry, with regulations for liquefied natural gas following in 1980, interstate hazardous liquid in 1981, and intrastate hazardous liquid in 1985.

Generally, in the event of a significant pipeline accident, it is understood that the NTSB will take primary charge of the incident and accident report itself, while the OPS will take primary charge of oversight of the return-to-service of the pipeline. Normally representatives from both agencies respond to the scene of a pipeline rupture as soon as practical to ensure data collection and dissemination to the various technical disciplines involved.

12.3 Initial Report

The Accident Report form for liquid lines is available on-line from the OPS. Form No. 7000-1 (01-2001) "Accident Report – Hazardous Liquid Pipeline Systems," which also has a companion document: "Instructions for Form RSPA F 7000-1 (01-2001). Accident Report – Hazardous Liquid Pipe Systems." Similarly, for gas lines there is Form 7100.2 (01-2002) "Incident Report-Gas Transmission and Gathering Systems" with its companion document: "Instructions for Form RSPA F 7100.2 (01-2002) Incident Report – Gas Transmission and Gathering Systems."

These forms and companion instruction documents, compiled by the Operator, form the baseline evaluation for any incident. The intent of the initial notification, other than documentation for the records, is to gain adequate knowledge to determine the urgency for a regulatory representative or others to be dispatched to the incident site and to establish awareness level of the Operator. The on-line forms adequately cover the information requirements for this initial phase.

12.4 Site Security and Data Collection

The fist priority of all is to ensure the site is totally secure and threats have been removed adequately to allow for special team investigations to proceed.

If SCC is suspected, the information and data examination should be broadened to ensure that all pertinent information about the incident is collected. In this case, the data collection efforts should be augmented to include relevant data to enable the evaluation of the particular problem, as well as to better enable oversight for return-to-service efforts. The following is recommended information to be gathered after the site is secure. This information is intended to be much more accurate and precise than initial report data, but still subject to change as a detailed evaluation continues. The operator should have qualified personnel to gather such data, especially if SCC is suspected, and regulatory oversight and collaboration is recommended at this stage. If no cause is readily apparent, note that the data collection for SCC may be prudent, especially for line segments that are considered susceptible to SCC.

1. Location of incident relative to nearest town.
2. Location of incident relative to the pipeline features.
3. Physical description of pipeline at Incident location:
• Diameter. • Wall thickness. • Grade of pipe. • Manufacturer of pipe. • Date of manufacture of pipe. • Type of Longitudinal weld. • Date of Construction of pipeline.
• Type of pipe coating. Include manufacturer/supplier, grade, original construction or replacement, date of installation.
• Type of coating joint system (if applicable). Include manufacturer/supplier, grade, original construction or replacement, date of installation.
4. Operating conditions of the pipeline at time of Incident:

• U/S Station discharge pressure immediately prior to Incident. • D/S Station discharge pressure immediately prior to Incident. • Estimated pipeline pressure at Incident site immediately prior to Incident. • Estimated throughput at Incident site immediately prior to Incident. • U/S Station discharge temperature immediately prior to Incident. • D/S Station discharge temperature immediately prior to Incident. • Estimated pipeline temperature at Incident site immediately prior to Incident. • Describe any other operating parameters that may have affected the integrity of the pipeline. (Unusual pressure/temperature cycles, extreme demand situations, valve closures, station shut downs, major customer usage variances, etc.)
5. Environmental conditions near the pipeline at time of Incident:
• Temperature • General weather description. Photos required. (Clear, Rain, Snow, Ice storm, etc.) • Topography description: ⇒ Lay of land in General Area. Photos required. (Flat, rolling hills, mountainous, lakebed, etc.) ⇒ Lay of land at Incident site. Photos required. (Hill top, valley, creek bottom, side hill, etc.) ⇒ Depiction of Incident site relative to the public. Photos required. (Remote – no populace, remote – near a farm house, remote – near several homes and a community center, in small town, near a small town, in a large city, near a large city, etc.) ⇒ Depiction of Incident site relative to Environmental issues. Photos required. (No significant threat, nearest stream 3 miles away, near the Kenai River, in Galveston Bay, etc.) • Type of soil (general characterization, e.g. sand, silt…) • pH of soil in the area: ⇒ Take readings with litmus paper and extract lab samples in uncontaminated soil as close to the origin as possible. ⇒ Take readings with litmus paper and extract lab samples at all four quadrants around the pipe. ⇒ Take readings with litmus paper and extract lab samples (four-quadrant) U/S and D/S of the origin. ⇒ Take readings with litmus paper and extract lab samples at several intervals on both sides of the pipe down at a depth equal to the bottom of the pipe. ⇒ Take steps to preserve the identity and integrity of the samples so that they may be further evaluated by a laboratory if deemed necessary. ⇒ Prepare sketch to show where all readings and samples were taken.
6. Physical description of the damage to human life.
7. Physical description of the damage to property. Photos required.
8. Physical description of the damage to the Environment. Photos required.
9. Physical description of the damage to the pipeline:
• Leak: